PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION

Question No. TIEC 2-15:

Will SWEPCO provide a guarantee on the amount of future capital expenditures and O&M expense for the wind facilities? If yes, please provide the level of guarantee that SWEPCO is willing to provide. If not, please explain why not.

Response No. TIEC 2-15:

SWEPCO continues to support the capital cost, PTC eligibility, and minimum production guarantees described in the Direct Testimonies of Company witnesses Brice and Smoak, because these are reasonable guarantees to provide in the context of this case.

Prepared By: Christopher N. Martel — Title: Regulatory Consultant Sr

Prepared By: Jonathan M. Griffin — Title: Regulatory Consultant Staff

Sponsored By: Thomas P. Brice — Title: VP Regulatory & Finance

PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION

Question No. TIEC 2-16:

What percentage of the NPV of the projected revenue requirement for the wind facilities is comprised of O&M expense and, separately, future capital expenditures?

Response No. TIEC 2-16:

The total NPV of the revenue requirement per line 6 of page 1 of Exhibit JFT 3 is $1,348 million. The NPV of SWEPCO's O&M is $157M, or 11.7% of the revenue requirement.

The NPV of the future capital expense would be the NPV of the 30 years of depreciation expense, plus the return on the rate base. Rate Base, which would be the future capital invested offset by accumulated depreciation and accumulated deferred income taxes, has not been separately computed so a return on that is not available.

The benefits model assumes all the future capital over the 31 year life of the facilities is all fully depreciated by 2051. The NPV of the depreciation expense is $57 million, or 4% of the revenue requirement NPV.

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PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION

Question No. TIEC 2-27:

Has SWEPCO ever quantified the value of fuel diversity? If so, please provide any such quantifications. If not, how does SWEPCO evaluate how much and what type of fuel diversity it needs, and how much to spend on fuel diversity?

Response No. TIEC 2-27:

Through its Integrated Resource Planning (IRP) process, SWEPCO evaluates various generating technologies to meet its SPP capacity obligation and energy needs, to provide a plan at least reasonable cost to its customers. Each technology includes estimates of its total cost and performance characteristics. Within the IRP model these are evaluated to a least cost plan. Various plans are developed based on varying load and commodity price forecasts and potentially other factors. For example, the Company may constrain the selection of a natural gas fired combined cycle to see what the model picks when this technology is not available.
In general, when the Company can diversify its fuel mix and lower cost to customers this is a relatively clear decision, due to the benefit that is provided by relying upon more than one, single fuel type. However, if diversifying its fuel mix will raise cost to customers, SWEPCO assesses whether there are any additional benefits to associate with the "diverse" addition to rationalize the additional cost. For example, this may include improved reliability over the non-diverse alternative due to the location on the grid or technology characteristics, such as fast responding battery storage versus a natural gas combustion turbine.

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PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION

Question No. TIEC 2-34:

Referring to page 5 of the Direct Testimony of Kamran Ali, where Mr. Ali states that congestion and curtailment risk is understated by PROMOD. Please provide the basis for this statement and any studies which support it or quantify how much PROMOD understates congestion and curtailment risk.

Response No. TIEC 2-34:

As Mr. Ali explains on page 5 of his testimony, congestion and curtailment risk is understated in PROMOD for a number of reasons:

- PROMOD is simulating a perfect day-ahead market under normalized and perfectly predictable load and system conditions.
- In PROMOD simulations, demand is normal and known for every hour, the transmission system does not encounter any outages, and the outage and generation schedule of all generating units is known in advance for the entire year along with their associated energy market bids.
- In real-time operations, however, conditions are not perfectly predictable, multiple transmission lines may be out of service at any given time, generation outages are not all predictable, wind and solar profiles may vary from their forecasts, and demand may be much higher or lower than normal.
- Furthermore, considering the number of computational parameters that a tool such as PROMOD can simulate to produce results, the number of flow gates (pairs of monitored elements and contingencies) is necessarily limited to a very small number compared to potential contingencies that could actually occur and result in system constraints. As a result, not all real-world events and their impacts are evaluated (which is also why a threshold deliverability analysis needs to be performed in addition to PROMOD simulations to more fully understand the risk of congestion and curtailment).

Mr. Pfeifenberger similarly explains this point on in his testimony (see page 5 line 15 through page 6 line 5), stating:

> "The PROMOD simulations, like those of similar other nodal market simulations, make certain simplified assumptions about market conditions that tend to yield conservatively low market price fluctuations and congestion levels. For example, PROMOD simulations generally use long-term projections of fuel prices (which do not have as much daily and monthly volatility as actual fuel prices), weather-normalized loads (which do not include occasional heat waves or unusual cold weather), and a fully intact transmission system (i.e., no temporary transmission outages). Thus, the simulations do not capture the actual daily or

monthly fluctuations in these variables, nor the added stresses associated with the encountered more challenging system conditions. The simulations are based on perfect foresight of daily real-time conditions—which approximates day-ahead power markets but understates real-time market uncertainties, including variances in wind generation output and therefore the likely generation curtailment driven by the uncertainty of real-time market conditions and temporary transmission outages."

See also the discussion of the limitations of production cost simulations in Chang, Pfeifenberger, and Hagerty, The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013, pages 35-46.[1]

PROMOD's assumption of a fully intact transmission system is perhaps the most intuitive reason for why the simulations tend to understate congestion and curtailments. By assuming that transmission facilities are available 100 percent of the time, the simulation analyses tend to under-estimate both congestion and curtailments. This is because outages, when they occur, typically cause transmission constraints to bind more frequently and increase transmission congestion and the associated customer costs significantly. For example, a 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20 percent lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37 percent lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50 percent lower; and that simulations without outages generally understated prices in eastern PJM load zones and overall west-east price differentials.[2]

Similarly, uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change. From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations approximate day-ahead conditions (i.e., perfect foresight) and consequently do not consider these uncertainties and their impacts.[3]

[1] Available at: https://brattlefiles.blob.core.windows.net/files/6257_the_benefits_of_electric_transmission_-_identifying_and_analyzing_the_value_of_investments_chang_pfeifenberger_hagerty_jul_2013.pdf.
[2] Id., pp. 37-39.
[3] Id., p. 41.

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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTH REQUEST FOR INFORMATION

Question No. TIEC 5-7:

Referring to SWEPCO's Response to TIEC 1-6, please provide the workpapers used to calculate the standard deviation that AEP used in creating the Low and High Cases presented in this case.

Response No. TIEC 5-7:

Please find TIEC_5_07_Attachment_1 on the attached flash drive.

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Sponsored By: Karl R. Bletzacker Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTH REQUEST FOR INFORMATION

Question No. TIEC 5-9:

Referring to SWEPCO's Response to TIEC 2-17, please provide the bases for SWEPCO's assumption that the additional wind facilities will be built in the SPP regardless of SWEPCO ownership.

Response No. TIEC 5-9:

The Company believes that because the selected facilities and others in the SPP footprint are in advanced stages of the SPP interconnection process, it is reasonable to assume that the selected or similar other facilities would likely be built regardless of whether or not SWEPCO purchases them. As a result, the Company believes that whether SWEPCO purchases the selected wind facilities will not have a significant impact on the total amount of wind generation in the SPP footprint.

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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SIXTH REQUEST FOR INFORMATION

Question No. TIEC 6-1:

Please explain why the Aurora model was used for forecasting the Southwest Power Pool locational marginal prices used in the economic analysis of the North Central Energy Facilities rather than the PROMOD methodology that was used in the economic analysis of Wind Catcher.

Response No. TIEC 6-1:

In Wind Catcher, the company's analysis focused on evaluating: (1) the value of buying 1,900 MW of wind capacity (as opposed to a baseline market-purchase case); and (2) the value of buying the 1,900 MW of the Windcatcher project accessing high-quality wind resources in the Oklahoma panhandle and delivering the energy to Tulsa North without the risk of curtailments or congestion (compared to buying the same amount of generation from generic wind resources in the SPP footprint).

These assessments required different nodal market simulations of the Base Case (i.e., the baseline market purchase case), the Generic Wind Case and Wind Catcher Project Case. This is because each of these cases would result in very different congestion and loss-related cost exposure for SWEPCO's customers, and those costs had to be analyzed to understand the relative value of purchasing 1,900 MW of generic wind capacity from across SPP versus purchasing 1,900 MW via the proposed Wind Catcher project. Further, since the two alternatives analyzed for purchasing this 1,900 MW of wind capacity (i.e., via the Generic Wind case and the Wind Catcher case) were so different in their impact on transmission system congestion and losses, and on the company's existing wind resources, it was necessary to also capture the differences in the market prices between these cases in the company's benefits analyses. Therefore, PROMOD was utilized to separately model each of these three cases and to estimate the case-specific near-term (2020 and 2025) market prices, and wind-related congestion and loss costs. PROMOD-based 2025 prices were then extrapolated based on the company's Aurora-based fundamental forecast for estimating the long-term market prices for the rest of the 25-yr study period. These prices were then used in the company's PLEXOS-based benefits analyses.

In this case, the focus is on the benefit of procuring the Selected Wind Facilities, and not also on other alternative means of wind procurement, such as with the Generic Wind Case in the Wind Catcher docket, and their impacts on market prices. Further, in the current analysis it is assumed that, whether or not the company purchases the Selected Wind Facilities, these facilities (or facilities that amount to similar total wind capacity, located in similar locations) will get developed in any case. This means that the wholesale market prices used in the company's PLEXOS benefits analyses will not be measurably different between a baseline reference case and the Selected Wind Facilities project case. This also means that the congestion and loss costs associated with the delivery of energy from the Selected Wind Facilities—which can only be evaluated in PROMOD—can be evaluated for just one PROMOD case that includes the Selected Wind Facilities. These congestion and loss results can then be combined with the company's Aurora-based fundamental forecast for long-term market prices across various sensitivities. Since the company has always relied on its Aurora-based projection of long-term wholesale power prices in its PLEXOS modeling for Integrated Resource Planning needs and customer impact purposes, adding only the congestion and loss costs to the Aurora-based long-term price forecasts is suitable for the evaluation of the costs and benefits of the Selected Wind Facilities.

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Sponsored by: Johannes P. Pfeifenberger | Title: Principal, The Brattle Group

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-3:

Does AEP agree that there is a trend toward shorter contract lengths for renewable power contracts with C&I customers? If not, provide a detailed description of why AEP does not believe that renewable power contract lengths are becoming shorter for C&I customers and any supporting documents.

Response No. TIEC 7-3:

The attachment responsive to this request is CONFIDENTIAL under the terms of the Protective Order. The Confidential information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours.

Yes, when considering Virtual Power Purchase Agreements (VPPA), the most common form of C&I renewable energy contract. Under this type of structure, the output (power) would be sold (liquidated) into the market and then the renewable energy credits (RECs) are retained by the C&I customer in order to meet their individual corporate sustainability goals.

The volume of corporate renewable deals has grown significantly over the past several years including to approximately 6.5 GW in 2018, as shown in TIEC 7-3 Confidential Attachment 1. These deals include a variety of structures, including VPPAs, green power purchases, green tariffs, or other special bilateral transactions – all of which have varying term length options.

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Prepared By: Edward J. Locigno	Title: Regulatory Analysis & Case Mgr
Prepared By: Zachary M. Yetzer	Title: Energy Bus Dev Analyst Sr
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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-4:

Does AEP agree or disagree that there is a trend toward renewable generators taking more merchant risk for the energy output of their plants, particularly for the later years of the facility's life? If the answer is disagree, please provide a detailed description of why AEP does not believe that renewable generators are taking more merchant risk for the energy output of their plants and any supporting documents.

Response No. TIEC 7-4:

AEP recognizes that non-regulated or IPP renewable developers (those without obligation to serve their regulated customers) have increasingly gravitated towards offering VPPAs to C&I customers in a contract-for-differences or hedge structure for a fixed term. Following the fixed term of the VPPA, the developer bears the risk but can also reap any potential benefits of higher prices in the merchant market over the remaining project life.

In an ownership structure such as the Selected Wind Facilities, the Company and its customers are able to benefit from 1) the Production Tax Credit in the first ten years and 2) the value of the facilities' generation in the market for at least 30 years.

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SOAH DOCKET NO. 473-19-6862
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-10:

Please describe how AEP in creating its Fundamental Forecasts of natural gas prices accounts, if at all, for known unknowns and the possibility of unknown unknowns.

Response No. TIEC 7-10:

Regarding the formation of AEPSC's long-term natural gas price forecast, known unknowns must be based on "substantial evidence" before being considered. Substantial evidence is enough evidence that a reasonable mind could accept as adequate support for inclusion in a long-term forecast. For example, substantive Final Investment Decisions in technological advances affecting long-term prices and trends would qualify as substantial evidence. The possibility of unknown unknowns are assumed to be in balance and ultimately exert no upward or downward bias to long-term forecasted natural gas prices. Ultimately, the future outcomes, events, circumstances, or consequences that cannot be planned for are approximated within the bounds of the Company's High and Low Band forecasts.

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SOAH DOCKET NO. 473-19-6862
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-11:

Does SWEPCO agree that the AEP Fundamentals Forecast natural gas prices it has presented to the PUCT over the last ten years have generally been higher than actual realized natural gas prices? If not, please explain why SWEPCO believes that its natural gas price forecasts have not been generally too high.

Response No. TIEC 7-11:

Yes. However, the Company does not believe hindsight is a valid way to evaluate a forecast. Over the last ten years the Company's natural gas prices presented in the AEP Fundamentals Forecast has generally tended to be higher than actual realized natural gas prices for many reasons, as have other natural gas price forecasts. Some of the circumstances that affect the natural gas market include abnormal weather, legislative/regulatory activity, demographics and the utilization of emerging technologies that cannot be fully anticipated. In the period from 2005 through 2010, Henry Hub natural gas spot prices averaged $6.62/MMBtu and have trended downward to average $3.22/MMBtu during the last 10 years (2011-2019). The Company's natural gas price forecasts have also trended downward. The differences in each of the Company's successive natural gas price forecasts document the changes in best available information at the time.

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SOAH DOCKET NO. 473-19-6862
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-12:

Please provide all documents from the last ten years regarding lessons that SWEPCO/AEP have learned regarding natural gas price forecasting.

Response No. TIEC 7-12:

The Company has not identified any documents concerning "lessons learned" regarding natural gas forecasting. The Company's Fundamentals Forecasts, including natural gas price forecasts, are not predictions of energy market outcomes but are modeled projections of what may happen given the best available information at the time they are prepared. Known drivers are included, known unknowns are judged for "substantial evidence" and the bias of unknown unknowns is considered. Please see the Company's response to TIEC 7-10 and 7-11.

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SOAH DOCKET NO. 473-19-6862
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SEVENTH REQUEST FOR INFORMATION

Question No. TIEC 7-13:

Please describe all changes to SWEPCO/AEP's natural gas price forecasting methodology that have occurred during the past ten years and provide any supporting documents.

Response No. TIEC 7-13:

AEPSC has made no changes in forecasting methodology in the prior ten years. The Fundamentals Forecast methodology continues to rely on the Aurora energy market simulation model for its projections resulting from best-available data.

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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH REQUEST FOR INFORMATION

Question No. TIEC 9-3:

Has SWEPCO/AEP analyzed the probability of a carbon tax or similar carbon burden being enacted during the 2021-2051 period? If so, please provide any such analyses.

Response No. TIEC 9-3:

Yes. The Fundamentals Forecast employed a CO_2 dispatch burden on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per metric ton commencing in 2028. This CO_2 dispatch burden was the same across the Base, High and Low Cases and is a proxy for other pathways CO_2 mitigation may take in addition to any regulation to impose fees on the combustion of carbon-based fuels. It is the assessment of Company experts that the likelihood of any federal climate legislation is very low over the next two years. With 2021-2023 as the earliest reasonable date for a climate proposal to pass through committee, reach the floor and be approved for eventual passage, there will be an implementation period of approximately five years (as seen in previous climate proposals). Thus, 2028 is the earliest reasonable projection as to when such legislation could become effective. The Fundamentals Forecast is not merely concerned with the current status of regulations and other current conditions that affect prices, but instead must also reflect reasonable expectations regarding future conditions that affect prices. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the current prospects for carbon regulations or other proxies for CO_2 mitigation costs and potential changes thereto. The Company has also provided analyses with an assumption of no carbon burden.

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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

<u>SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH REQUEST FOR INFORMATION</u>

Question No. TIEC 9-5:

Has SWEPCO/AEP analyzed the possibility of the wind production tax credit (PTC) or a similar subsidy for wind generation being reenacted during the 2021-2051 period? If so, please provide any such analyses.

Response No. TIEC 9-5:

In light of the comprehensive PTC phase out recently enacted by Congress, SWEPCO/AEP does not believe there is a substantial likelihood of the PTC or similar subsidy for wind generation being reenacted in the near term. The Company's tax planning and forecasting is based on current law and does not incorporate predictions regarding future legislative activity. SWEPCO/AEP has not analyzed that possibility for the latter part of the 2021-2051 period.

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SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' TENTH REQUEST FOR INFORMATION

Question No. TIEC 10-1:

Referring to SWEPCO's response to TIEC 7-1:

a. What is the SPP trading hub closest to SWEPCO's generation?

b. Does SWEPCO have access to any forward price data for that trading hub?

c. If so, to what data does SWEPCO have access?

d. If not, please explain why not.

e. Does SWEPCO retain any forward price data for that trading hub?

f. If so, what data does SWEPCO retain?

g. If not, please explain why not.

h. Please provide the most recent 7X24 forward price strip in SWEPCO's possession and the date of that strip for the SPP trading hub closest to SWEPCO generation.

i. Please provide the most recent on-peak forward price strip in SWEPCO's possession and the date of that strip for the SPP trading hub closest to SWEPCO generation.

j. Please provide the natural gas price strip that corresponds to each of the forward price strips in (h) and (i).

Response No. TIEC 10-1:

a. The SPP South Hub futures contract traded on the Intercontinental Exchange (ICE) platform. Also note, the total number of ICE SPP South Fixed Price futures contracts (*i.e.* Open Interest, or "OI") is extremely low in the near term and *de minimis* (or zero) thereafter indicating illiquidity.

b. Yes.

c. AEPSC's Power Trading Desk receives forward curve marks each evening from ICAP Energy (an energy brokerage firm). AEPSC power traders also have the ability to view products trading on the Intercontinental Exchange (ICE) platform.

d. N/A

e. No.

f. N/A

g. The Company does not retain historic data from the SPP South ICE futures market. It is available from ICE at: https://www.theice.com/marketdata/reports/142

h - i. Please see TIEC 10-1 Attachments 1 and 2.

j. The natural gas futures price strip that corresponds to the ICE SPP South Hub Fixed Price Futures contract is the sum of: 1) NYMEX Panhandle Natural Gas (Platts IFERC) Basis Futures, and; 2) Henry Hub Natural Gas Futures. Henry Hub values alone do not represent the value of natural gas corresponding to the SPP South Hub. The benchmark Henry Hub natural gas values must be adjusted by the Panhandle natural gas basis differential to yield the locational value of natural gas at the SPP South Hub. Please see TIEC 10-1 Attachment 3.

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Futures Daily Market Report for Financial Power
18-Nov-2019

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE OPEN#	HIGH	LOW	CLOSE#	SETTLE PRICE	CHANGE	TOTAL VOLUME	VOLUME AND OI TOTALS OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSO-SPP South Hub Day-Ahead Off-Peak Fixed Price Future														
FSO	Nov19					17.68	-1.19	0	136	0	0	0	0	0
FSO	Dec19					19 25	-0 35	0	126	0	0	0	0	0
FSO	Jan20					21.75	-0.35	0	130	0	0	0	0	0
FSO	Feb20					20 95	-0 30	0	135	0	0	0	0	0
FSO	Mar20					16 55	-0 05	0	168	0	0	0	0	0
FSO	Apr20					14 75	-0 05	0	168	0	0	0	0	0
FSO	May20					15 10	0.00	0	98	0	0	0	0	0
FSO	Jun20					15 95	-0.05	0	103	0	0	0	0	0
FSO	Jul20					20.20	-0.15	0	98	0	0	0	0	0
FSO	Aug20					18.85	-0.15	0	98	0	0	0	0	0
FSO	Sep20					16 15	0.00	0	98	0	0	0	0	0
FSO	Oct20					15 20	-0.05	0	188	0	0	0	0	0
FSO	Nov20					15.50	-0.05	0	188	0	0	0	0	0
FSO	Dec20					17.05	-0.05	0	188	0	0	0	0	0
FSO	Jan21					20.75	0.00	0	130	0	0	0	0	0
FSO	Feb21					19 80	0.00	0	130	0	0	0	0	0
FSO	Mar21					14 60	0 05	0	125	0	0	0	0	0
FSO	Apr21					13 20	0 05	0	125	0	0	0	0	0
FSO	May21					14.15	0.05	0	135	0	0	0	0	0
FSO	Jun21					14.65	0.05	0	135	0	0	0	0	0
FSO	Jul21					19.80	0.05	0	135	0	0	0	0	0
FSO	Aug21					17.60	0.05	0	135	0	0	0	0	0
FSO	Sep21					14.55	0.05	0	135	0	0	0	0	0
FSO	Oct21					13.90	0.05	0	125	0	0	0	0	0
FSO	Nov21					14.95	0.05	0	125	0	0	0	0	0

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COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSO	Dec21					17.75	0.05	0	125	0	0	0	0	0
FSO	Jan22					21.20	0.05	0	96	0	0	0	0	0
FSO	Feb22					19.50	0.05	0	96	0	0	0	0	0
FSO	Mar22					14.80	0.15	0	89	0	0	0	0	0
FSO	Apr22					13.65	0.15	0	89	0	0	0	0	0
FSO	May22					12.85	0.10	0	96	0	0	0	0	0
FSO	Jun22					12.75	0.10	0	96	0	0	0	0	0
FSO	Jul22					17.20	0.10	0	96	0	0	0	0	0
FSO	Aug22					15.60	0.10	0	96	0	0	0	0	0
FSO	Sep22					11.90	0.10	0	96	0	0	0	0	0
FSO	Oct22					13.10	0.10	0	89	0	0	0	0	0
FSO	Nov22					14.45	0.10	0	89	0	0	0	0	0
FSO	Dec22					16.90	0.15	0	89	0	0	0	0	0
FSO	Jan23					20.55	0.15	0	20	0	0	0	0	0
FSO	Feb23					19.15	0.15	0	20	0	0	0	0	0
FSO	Mar23					14.05	0.10	0	20	0	0	0	0	0
FSO	Apr23					12.60	0.10	0	20	0	0	0	0	0
FSO	May23					11.75	0.05	0	20	0	0	0	0	0
FSO	Jun23					12.05	0.05	0	20	0	0	0	0	0
FSO	Jul23					17.35	0.10	0	20	0	0	0	0	0
FSO	Aug23					15.60	0.10	0	20	0	0	0	0	0
FSO	Sep23					12.15	0.05	0	20	0	0	0	0	0
FSO	Oct23					12.50	0.05	0	20	0	0	0	0	0
FSO	Nov23					13.80	0.10	0	20	0	0	0	0	0
FSO	Dec23					15.80	0.10	0	20	0	0	0	0	0
FSO	Jan24					19.60	0.15	0	6	0	0	0	0	0
FSO	Feb24					18.40	0.15	0	6	0	0	0	0	0
FSO	Mar24					13.65	0.10	0	6	0	0	0	0	0

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SOAH Docket No. 473-19-6862
PUC Docket No. 49737
TIEC:s 10th, Q. # TIEC 10-1
Attachment 1
Page 2 of 5

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSO	Apr24					12.30	0.10	0	6	0	0	0	0	0
FSO	May24					11.40	0.05	0	6	0	0	0	0	0
FSO	Jun24					11.70	0.05	0	6	0	0	0	0	0
FSO	Jul24					17.05	0.10	0	6	0	0	0	0	0
FSO	Aug24					15.65	0.10	0	6	0	0	0	0	0
FSO	Sep24					11.85	0.05	0	6	0	0	0	0	0
FSO	Oct24					12.30	0.05	0	6	0	0	0	0	0
FSO	Nov24					13.65	0.10	0	6	0	0	0	0	0
FSO	Dec24					15.45	0.10	0	6	0	0	0	0	0
FSO	Jan25					19.10	0.15	0	7	0	0	0	0	0
FSO	Feb25					18.05	0.15	0	7	0	0	0	0	0
FSO	Mar25					13.50	0.10	0	7	0	0	0	0	0
FSO	Apr25					12.15	0.10	0	7	0	0	0	0	0
FSO	May25					11.40	0.05	0	7	0	0	0	0	0
FSO	Jun25					11.80	0.05	0	7	0	0	0	0	0
FSO	Jul25					16.90	0.10	0	7	0	0	0	0	0
FSO	Aug25					15.55	0.10	0	7	0	0	0	0	0
FSO	Sep25					11.85	0.05	0	7	0	0	0	0	0
FSO	Oct25					12.30	0.05	0	7	0	0	0	0	0
FSO	Nov25					13.65	0.10	0	7	0	0	0	0	0
FSO	Dec25					15.40	0.10	0	7	0	0	0	0	0
FSO	Jan26					18.95	0.15	0	1	0	0	0	0	0
FSO	Feb26					17.75	0.15	0	1	0	0	0	0	0
FSO	Mar26					13.25	0.10	0	1	0	0	0	0	0
FSO	Apr26					11.80	0.10	0	1	0	0	0	0	0
FSO	May26					11.20	0.05	0	1	0	0	0	0	0
FSO	Jun26					11.55	0.05	0	1	0	0	0	0	0
FSO	Jul26					16.75	0.10	0	1	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSO	Aug26					15.30	0.10	0	1	0	0	0	0	0
FSO	Sep26					11.65	0.05	0	1	0	0	0	0	0
FSO	Oct26					12.00	0.05	0	1	0	0	0	0	0
FSO	Nov26					13.30	0.10	0	1	0	0	0	0	0
FSO	Dec26					15.15	0.10	0	1	0	0	0	0	0
FSO	Jan27					18.85	0.15	0	1	0	0	0	0	0
FSO	Feb27					17.65	0.15	0	1	0	0	0	0	0
FSO	Mar27					13.20	0.10	0	1	0	0	0	0	0
FSO	Apr27					11.75	0.10	0	1	0	0	0	0	0
FSO	May27					11.10	0.05	0	1	0	0	0	0	0
FSO	Jun27					11.45	0.05	0	1	0	0	0	0	0
FSO	Jul27					16.55	0.10	0	1	0	0	0	0	0
FSO	Aug27					15.20	0.10	0	1	0	0	0	0	0
FSO	Sep27					11.45	0.05	0	1	0	0	0	0	0
FSO	Oct27					11.85	0.05	0	1	0	0	0	0	0
FSO	Nov27					13.25	0.10	0	1	0	0	0	0	0
FSO	Dec27					15.15	0.10	0	1	0	0	0	0	0
FSO	Jan28					18.80	0.15	0	6	0	0	0	0	0
FSO	Feb28					17.60	0.15	0	6	0	0	0	0	0
FSO	Mar28					13.05	0.10	0	6	0	0	0	0	0
FSO	Apr28					11.85	0.10	0	6	0	0	0	0	0
FSO	May28					11.05	0.05	0	6	0	0	0	0	0
FSO	Jun28					11.40	0.05	0	6	0	0	0	0	0
FSO	Jul28					16.60	0.10	0	6	0	0	0	0	0
FSO	Aug28					15.10	0.10	0	6	0	0	0	0	0
FSO	Sep28					11.45	0.05	0	6	0	0	0	0	0
FSO	Oct28					11.85	0.05	0	6	0	0	0	0	0
FSO	Nov28					13.15	0.10	0	6	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSO	Dec28					15.00	0.10	0	6	0	0	0	0	0
Totals for FSO:								0	5,091	0	0	0	0	0

NOTE: The information contained in his report is compiled for the convenience of subscribers and is furnished without responsibility for accuracy and is accepted by the subscriber on the condition that errors or omissions shall not be made the basis for any claim, demand or cause of action.

NOTE: OI information is not available un il the next business day.

NOTE: Volume is aggregated and representative of each Futures market strip including applicable TAS trading activity.

Open and Close prices reflect the first and last trade in the market and do not correlate to any opening or closing periods.

NOTE: Spread Volume includes futures/options combinations, spreads, and defined strategies.

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Futures Daily Market Report for Financial Power
18-Nov-2019

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE OPEN#	HIGH	LOW	CLOSE#	SETTLE PRICE	CHANGE	TOTAL VOLUME	OI	VOLUME AND OI TOTALS CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSP-SPP South Hub Day-Ahead Peak Fixed Price Future														
FSP	Nov19					26.74	0.59	0	318	0	0	0	0	0
FSP	Dec19					28.70	-0.50	0	223	0	0	0	0	0
FSP	Jan20					32.55	-0.40	0	284	0	0	0	0	0
FSP	Feb20					30 60	-0.30	0	284	0	0	0	0	0
FSP	Mar20					26 00	-0.45	0	119	0	0	0	0	0
FSP	Apr20					24 95	-0 10	0	94	0	0	0	0	0
FSP	May20					26.55	-0.10	0	104	0	0	0	0	0
FSP	Jun20					28 05	-0.10	0	104	0	0	0	0	0
FSP	Jul20					34.30	-0.05	0	129	0	0	0	0	0
FSP	Aug20					32 15	-0.05	0	129	0	0	0	0	0
FSP	Sep20					28.10	-0.10	0	104	0	0	0	0	0
FSP	Oct20					24 55	-0.10	0	123	0	0	0	0	0
FSP	Nov20					24.20	-0.10	0	119	0	0	0	0	0
FSP	Dec20					26.45	0.05	0	89	0	0	0	0	0
FSP	Jan21					30 25	-0.10	0	163	0	0	0	0	0
FSP	Feb21					28 00	-0.10	0	163	0	0	0	0	0
FSP	Mar21					25.70	-0.05	0	168	0	0	0	0	0
FSP	Apr21					23.40	-0 05	0	168	0	0	0	0	0
FSP	May21					24.95	-0.05	0	168	0	0	0	0	0
FSP	Jun21					25.45	0.00	0	168	0	0	0	0	0
FSP	Jul21					35.70	-0 10	0	163	0	0	0	0	0
FSP	Aug21					32.00	-0.10	0	163	0	0	0	0	0
FSP	Sep21					26.25	0.00	0	168	0	0	0	0	0
FSP	Oct21					22.80	-0 05	0	168	0	0	0	0	0
FSP	Nov21					24.15	-0.05	0	168	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSP	Dec21					27.00	-0.05	0	168	0	0	0	0	0
FSP	Jan22					32.00	0.05	0	83	0	0	0	0	0
FSP	Feb22					30.00	0.05	0	83	0	0	0	0	0
FSP	Mar22					23.65	0.05	0	83	0	0	0	0	0
FSP	Apr22					22.00	0.05	0	83	0	0	0	0	0
FSP	May22					22.40	0.05	0	83	0	0	0	0	0
FSP	Jun22					23.35	0.05	0	83	0	0	0	0	0
FSP	Jul22					35.60	0.05	0	78	0	0	0	0	0
FSP	Aug22					32.25	0.05	0	78	0	0	0	0	0
FSP	Sep22					24.20	0.05	0	83	0	0	0	0	0
FSP	Oct22					22.05	0.05	0	83	0	0	0	0	0
FSP	Nov22					23.30	0.05	0	83	0	0	0	0	0
FSP	Dec22					25.30	0.05	0	83	0	0	0	0	0
FSP	Jan23					31.85	0.05	0	20	0	0	0	0	0
FSP	Feb23					29.70	0.05	0	20	0	0	0	0	0
FSP	Mar23					22.00	0.05	0	20	0	0	0	0	0
FSP	Apr23					20.35	0.05	0	20	0	0	0	0	0
FSP	May23					21.80	0.05	0	20	0	0	0	0	0
FSP	Jun23					23.25	0.05	0	20	0	0	0	0	0
FSP	Jul23					34.65	0.05	0	20	0	0	0	0	0
FSP	Aug23					30.90	0.05	0	20	0	0	0	0	0
FSP	Sep23					22.85	0.05	0	20	0	0	0	0	0
FSP	Oct23					20.75	0.05	0	20	0	0	0	0	0
FSP	Nov23					21.90	0.05	0	20	0	0	0	0	0
FSP	Dec23					23.70	0.05	0	20	0	0	0	0	0
FSP	Jan24					31.05	0.00	0	0	0	0	0	0	0
FSP	Feb24					29.35	0.00	0	0	0	0	0	0	0
FSP	Mar24					21.55	0.00	0	0	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSP	Apr24					19.75	0.00	0	0	0	0	0	0	0
FSP	May24					21.55	0.00	0	0	0	0	0	0	0
FSP	Jun24					22.85	0.00	0	0	0	0	0	0	0
FSP	Jul24					34.25	0.00	0	0	0	0	0	0	0
FSP	Aug24					30.90	0.00	0	0	0	0	0	0	0
FSP	Sep24					22.40	0.00	0	0	0	0	0	0	0
FSP	Oct24					20.55	0.00	0	0	0	0	0	0	0
FSP	Nov24					21.65	0.00	0	0	0	0	0	0	0
FSP	Dec24					23.40	0.00	0	0	0	0	0	0	0
FSP	Jan25					31.25	0.00	0	1	0	0	0	0	0
FSP	Feb25					29.20	0.00	0	1	0	0	0	0	0
FSP	Mar25					21.75	0.00	0	1	0	0	0	0	0
FSP	Apr25					19.90	0.00	0	1	0	0	0	0	0
FSP	May25					21.55	0.00	0	1	0	0	0	0	0
FSP	Jun25					22.90	0.00	0	1	0	0	0	0	0
FSP	Jul25					33.25	0.00	0	1	0	0	0	0	0
FSP	Aug25					29.75	0.00	0	1	0	0	0	0	0
FSP	Sep25					22.50	0.00	0	1	0	0	0	0	0
FSP	Oct25					20.55	0.00	0	1	0	0	0	0	0
FSP	Nov25					21.60	0.00	0	1	0	0	0	0	0
FSP	Dec25					23.25	0.00	0	1	0	0	0	0	0
FSP	Jan26					31.30	0.00	0	5	0	0	0	0	0
FSP	Feb26					29.15	0.00	0	5	0	0	0	0	0
FSP	Mar26					21.50	0.00	0	5	0	0	0	0	0
FSP	Apr26					19.90	0.00	0	5	0	0	0	0	0
FSP	May26					21.70	0.00	0	5	0	0	0	0	0
FSP	Jun26					22.85	0.00	0	5	0	0	0	0	0
FSP	Jul26					33.00	0.00	0	5	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSP	Aug26					29.70	0.00	0	5	0	0	0	0	0
FSP	Sep26					22.40	0.00	0	5	0	0	0	0	0
FSP	Oct26					20.55	0.00	0	5	0	0	0	0	0
FSP	Nov26					21.70	0.00	0	5	0	0	0	0	0
FSP	Dec26					23.15	0.00	0	5	0	0	0	0	0
FSP	Jan27					31.30	0.00	0	5	0	0	0	0	0
FSP	Feb27					29.30	0.00	0	5	0	0	0	0	0
FSP	Mar27					21.35	0.00	0	5	0	0	0	0	0
FSP	Apr27					19.80	0.00	0	5	0	0	0	0	0
FSP	May27					21.50	0.00	0	5	0	0	0	0	0
FSP	Jun27					22.95	0.00	0	5	0	0	0	0	0
FSP	Jul27					33.20	0.00	0	5	0	0	0	0	0
FSP	Aug27					29.75	0.00	0	5	0	0	0	0	0
FSP	Sep27					22.25	0.00	0	5	0	0	0	0	0
FSP	Oct27					20.45	0.00	0	5	0	0	0	0	0
FSP	Nov27					21.70	0.00	0	5	0	0	0	0	0
FSP	Dec27					23.00	0.00	0	5	0	0	0	0	0
FSP	Jan28					30.90	0.00	0	5	0	0	0	0	0
FSP	Feb28					28.90	0.00	0	5	0	0	0	0	0
FSP	Mar28					21.25	0.00	0	5	0	0	0	0	0
FSP	Apr28					19.60	0.00	0	5	0	0	0	0	0
FSP	May28					21.25	0.00	0	5	0	0	0	0	0
FSP	Jun28					22.60	0.00	0	5	0	0	0	0	0
FSP	Jul28					32.85	0.00	0	5	0	0	0	0	0
FSP	Aug28					29.25	0.00	0	5	0	0	0	0	0
FSP	Sep28					22.05	0.00	0	5	0	0	0	0	0
FSP	Oct28					20.25	0.00	0	5	0	0	0	0	0
FSP	Nov28					21.40	0.00	0	5	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME A						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
FSP	Dec28					22.90	0.00	0	5	0	0	0	0	0
Totals for FSP:								0	5,637	0	0	0	0	0

NOTE: The information contained in his report is compiled for the convenience of subscribers and is furnished without responsibility for accuracy and is accepted by the subscriber on the condition that errors or omissions shall not be made the basis for any claim, demand or cause of action.

NOTE: OI information is not available un il the next business day.

NOTE: Volume is aggregated and representative of each Futures market strip including applicable TAS trading activity.

\# Open and Close prices reflect the first and last trade in the market and do not correlate to any opening or closing periods.

NOTE: Spread Volume includes futures/options combinations, spreads, and defined strategies.

Natural Gas Forwards & Futures

As Of : 11/18/2019

Term	Panhandle
Dec 2019	1.972
Jan 2020	2.170
Feb 2020	2.081
Mar 2020	1.854
Apr 2020	1.707
May 2020	1.732
Jun 2020	1.787
Jul 2020	1.902
Aug 2020	1.915
Sep 2020	1.851
Oct 2020	1.823
Nov 2020	2.056
Dec 2020	2.268
Jan 2021	N/A
Feb 2021	N/A
Mar 2021	N/A
Apr 2021	1.886
May 2021	1.801
Jun 2021	1.841
Jul 2021	1.958
Aug 2021	1.951
Sep 2021	1.925
Oct 2021	1.915
Nov 2021	N/A
Dec 2021	N/A
2022	N/A
2023	N/A
2024	N/A
2025	N/A
2026	N/A
2027	N/A
2028	N/A

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' ELEVENTH REQUEST FOR INFORMATION

Question No. TIEC 11-5:

Referring to SWEPCO's Response to TIEC 6-2:

a. Please provide a list of generation capacity retirements in the SPP region determined by the Aurora model by year and by fuel type, including the net capacity and assumed heat rates of the retired units.

b. Does the Aurora model inputs allow for planned retirements or planned additions or are all capacity changes an output of the model?

c. Please provide a version of TIEC_6_02_Attachment_1 that breaks renewable capacity additions down between wind and solar separately.

Response No. TIEC 11-5:

a. & c. Please refer to TIEC_11_05_Attachment_1, provided electronically on the PUC Interchange.

b. The Aurora model allows for planned retirements (e.g. retirements upon reaching a certain age) and planned additions (e.g. units currently under construction). All other capacity changes are an output of the model (except the anticipated re-powering of wind facilities).

Prepared By: Connie S. Trecazzi Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' ELEVENTH REQUEST FOR INFORMATION

Question No. TIEC 11-6:

Referring to SWEPCO's Response to TIEC 6-3, please provide a version of TIEC_06_03_Attachment_1 that breaks renewable capacity additions down between wind and solar separately.

Response No. TIEC 11-6:

Please refer to TIEC_11_06_Attachment_1, provided electronically on the PUC Interchange.

Prepared By: Connie S. Trecazzi | Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker | Title: Dir Fundamental Analysis

TRANSCRIPT OF PROCEEDINGS

BEFORE THE

PUBLIC UTILITY COMMISSION OF TEXAS

AUSTIN, TEXAS

OPEN MEETING

THURSDAY, JULY 26, 2018

BE IT REMEMBERED THAT AT approximately 9:31 a.m., on Thursday, the 26th day of July 2018, the above-entitled matter came on for hearing at the Public Utility Commission of Texas, 1701 North Congress Avenue, William B. Travis Building, Austin, Texas, Commissioners' Hearing Room, before DeANN T. WALKER, CHAIRMAN, ARTHUR C. D'ANDREA and SHELLY BOTKIN, COMMISSIONERS; and the following proceedings were reported by William C. Beardmore, Certified Shorthand Reporter.

case. It's a little bit lower than the AEP low case, but it still would tell you that customers on a net present value basis are going to save hundreds of millions of dollars and billions on a nominal basis.

What we have here is a choice. We can certify this project or not. Are there risks associated with both choices? Yes, but the risk of not certifying the project are much greater. There's nothing that protects customers from higher energy prices and gas prices; whereas, on the low side the Company has provided many benefits.

COMM. D'ANDREA: Can I stop you there, Bill?

MR. COE: Yes, sir.

COMM. D'ANDREA: This is something that keeps coming up. There are good things that can protect them. Right? There's -- you could do a PPA. You could -- for example, instead of putting in rate base, you could presumably buy gas and sell -- I mean, there are ways to protect them.

You know, if we denied it, say, presumably you wouldn't just sit on your hands and say, whatever; we're stuck with natural gas now. We're not going to do anything. We're not going to buy wind. Right?

MR. COE: Correct. There are other ways

Exhibit CSG-3 HSPM

RFIs and Discovery Relied Upon

(CD)

HIGHLY SENSITIVE PROTECTED

MATERIAL PROVIDED TO PARTIES

PURSUANT TO PROTECTIVE ORDER